

Wanda's Business Services Group
University of Alberta
1-18 Business Building
Edmonton, Alberta T6G 2R6



Positive **Momentum**

“A high quality asset base and diverse capital structure
HAVE ALLOWED BAYTEX TO REACT TO **changing** market conditions.”

Dale O. Shwed, *President and Chief Executive Officer*



AN INDEPENDENT OIL & GAS COMPANY

Baytex is an independent oil and gas company engaged in the exploration, development and production of oil and natural gas. Our operations are concentrated in three core districts in the Western Canadian Sedimentary Basin. Baytex focuses on building an asset base through land acquisitions, seismic data interpretation, exploratory and development drilling, as well as property and corporate acquisitions. Our efforts are dedicated to properties that we believe will provide long-life reserves which will generate cash flow in the near term. We continually look for opportunities to enhance our position in our core areas, and we intend to pursue strategic acquisitions which are within our operating and financial parameters.

Notice of Annual Meeting

The annual meeting of shareholders of Baytex Energy Ltd. will be held in the Alberta Room of the Fairmont Palliser Hotel at 133 – 9th Avenue S.W., Calgary, Alberta on Tuesday, May 28, 2002 at 3:00 P.M. (MDT). All shareholders and other interested parties are invited to attend.

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IBC Directors

HIGHLIGHTS

2001 2000

FINANCIAL

(\$ thousands, except per share amounts)

Petroleum and natural gas sales	329,700	286,226
Cash flow from operations	144,070	155,326
Per share – basic	2.91	3.68
– diluted	2.87	3.58
Net income (loss)	(128,509)	43,788
Per share – basic	(2.60)	1.04
– diluted	(2.60)	1.01
Exploration and development	136,121	170,787
Acquisitions – net	239,964	214,070
Total capital expenditures	376,085	384,857
Working capital (deficiency)	24,861	(42,374)
Bank debt	74,254	128,372
Long-term notes	329,668	85,511
Total net debt	379,061	256,257

Cash flow from operations decreased by only 7 percent year-over-year despite a 22 percent reduction in overall commodity prices.

Loss for 2001 included a \$131.3 million non-cash ceiling test write-down.

Shares outstanding at December 31 (thousands)

Basic	52,008	45,797
Diluted	56,476	49,839

Total net debt was reduced by \$100 million at year-end through a fourth quarter disposition program.

OPERATING

Production

Conventional oil & NGLs (bbls/d)	5,152	4,107
Heavy oil (bbls/d)	26,533	20,005
Total oil & NGLs (bbls/d)	31,685	24,112
Natural gas (mmcf/d)	70.8	57.7
Barrels of oil equivalent (boe/d @ 6:1)	43,488	33,721

Reserves, proved & probable

Oil & NGLs (mbbls)	162,555	153,060
Natural gas (mmcf)	177,420	128,250
Barrels of oil equivalent (mboe @ 6:1)	192,125	174,435

Natural gas production was enhanced in 2001 with the acquisitions of OGY and Triumph.



Left to right: Raymond T. Chan, *Senior Vice-President and Chief Financial Officer*,
Dale O. Shwed, *President and Chief Executive Officer*

MESSAGE TO SHAREHOLDERS

The year 2001 was indeed eventful for Baytex and those connected to the oil and gas industry as well as the general population of the world.

Specifically to oil and gas, the year started with West Texas Intermediate (WTI) oil at US\$30.00/bbl and ended one-third lower at US\$20.00/bbl. Gas price exhibited even more volatility, with AECO price in excess of \$10.00/mcf at the beginning of January declining to barely over \$3.00/mcf at the end of December. The Canadian oil and gas industry saw an unprecedented amount of merger and acquisition activities in 2001, particularly in the mid-sized producers category where only a handful of these companies were left at year-end. Most importantly, the tragic events of September 11 and its fallout effects on the world's economy resulted in additional volatilities and challenges that are certain to be felt for a long time.

“THE COMPANY’S natural gas prospect inventory AT
YEAR-END 2001 is superior TO ANY OTHER TIME IN BAYTEX’S HISTORY.”

At Baytex, the operating strategy enunciated in our 1999 annual report to pursue growth through a dual commodity focus on heavy oil and natural gas was further realized. The Company recognizes the benefits of a more balanced production mix and the inherent risk in over-dependence on the fortunes of a single commodity. In order to expand the financing capacity of the Company to execute this strategy, Baytex issued US\$150 million of 10-year subordinated notes in February of 2001. Although this type of financing instrument is widely used by exploration and production companies in the United States, Baytex was, and still is, the only oil and gas company in Canada to have successfully completed a financing in the United States high-yield bond market.

A YEAR IN REVIEW: 2001 was a year that saw Baytex acquire quality assets providing a more diverse production base for future growth. ■ **Feb 12, 2001** Baytex announces completion of an offering of US\$150 million of senior subordinated notes. Net proceeds from the sale of the notes to be used for refinancing of existing debt and future acquisitions. ■ **Mar 30, 2001** Take-over bid made for the outstanding shares of OGY Petroleums Ltd. OGY's

The capacity created by this financing allowed Baytex to complete a series of acquisitions in the second quarter of 2001 which significantly enhanced the long-term prospects of the Company. Through the acquisition of OGY Petroleums, Baytex doubled its natural gas assets in the West of Four Central Alberta region. Through the acquisition of Triumph Energy, Baytex expanded its operations at Ferrier in West of Five Central Alberta, where it can pursue multi-zone, long-life, liquids-rich natural gas for years to come. As a result of these efforts, Baytex increased its natural gas production by nearly 40 percent in the fourth quarter of 2001 as compared to one year ago. More importantly, the Company's natural gas prospect inventory at year-end 2001 is superior to any other time in Baytex's history.

Heavy oil, in summary, was a forgotten commodity in 2001. Differentials had their worst ever year since price deregulation in 1985, with Lloyd Blend differentials averaging US\$10.69/bbl or 42 percent of the average WTI price of US\$25.90 during the year. In comparison, the highest differentials prior to 2001 were recorded in 1991 during the Gulf War, when Lloyd Blend differentials averaged US\$8.41/bbl or 39 percent of WTI price. The 16-year average differential since price deregulation is US\$5.83/bbl or 29 percent of WTI price. Recognizing the substandard economics, Baytex substantially reduced its exploration and development activities in heavy oil, and drilled only 58 wells in 2001 compared to the 260 wells drilled in 2000. Fortunately, Baytex also recognized the opportunities created by the unfavourable environment, and augmented its operations through two property acquisitions. The first one at Cold Lake represented the Company's first major heavy oil investment in the Province of Alberta. The second one at Carruthers further increased its dominant position as a conventional heavy oil player in that area in Western Saskatchewan. As in the case of the natural gas weighted corporate acquisitions, these two transactions significantly enhanced Baytex's prospect inventory for future growth in heavy oil.

Having completed these acquisitions, and realizing the resulting increased leverage on its balance sheet, Baytex embarked on a divestiture program of non-core properties to reduce bank debt and improve operating focus and efficiency. This plan was first made public in June. However, with the preparation time required to update reserve reports, and the unforeseen interruption of the marketing process by the events of September 11, the Company was not able to announce the results of this divestiture program until December. Unfortunately, the significant decline in commodity prices, combined with a sudden widening in heavy oil differentials due to a refinery outage, severely impacted Baytex's share price in the fourth quarter.

operations are concentrated in the east central Alberta area and adjacent to Baytex's core properties in Leahurst and Drumheller. ■ **Apr 11, 2001** Take-over bid made for the outstanding shares of Triumph Energy Corporation. Triumph's major properties are located at Ferrier, Sunchild, O'Chiese and Cow Lake and complement Baytex operations in these areas. ■ **May 16, 2001** Baytex acquires OGY Petroleums Ltd. as 21.47 million common shares of

Despite these challenges, the Company maintained confidence in its ability to operate through this most difficult cycle predicated on the quality of its asset base and the strength of its capital structure. Its patience in negotiating the asset sales resulted in fair value being received for the \$101 million of completed transactions. Baytex was also opportunistic in re-trading some of its commodity derivative contracts to realize \$19 million of cash proceeds, as well as swapping its fixed interest obligations for floating terms to reduce its near-term cash expenses. All these efforts significantly bolstered the Company's financial position and allowed it to welcome 2002 with enthusiasm and commitment.

The production cutbacks executed by world oil exporting countries and the reduction in capital spending allocated to conventional heavy oil projects by domestic producers, have combined to reduce heavy oil supply resulting in a dramatic narrowing of heavy oil differentials so far in 2002. Lloyd Blend differentials averaged US\$6.89/bbl in January and US\$5.71/bbl in February of 2002. It is currently around US\$5.00/bbl, resulting in wellhead prices for Baytex of approximately CAN\$25.00/bbl. These recent differentials are more in-line with the historical levels, where Lloyd Blend differentials per barrel were below US\$5.00 forty-one percent of the time, below US\$6.00 sixty percent of the time and below US\$7.00 eighty percent of the time in the 16-year period since deregulation. With the Citgo refinery projected to resume operations in April and the expected demand increase due to the commencement of paving season, the outlook for heavy oil is very favourable. Accordingly, Baytex has accelerated its heavy oil drilling program in order to take advantage of the improved economics.

With the asset divestiture program completed, Baytex is projecting its production in 2002 to average 2,800 bbls/d of light oil, 23,500 bbls/d of heavy oil and 72.0 mmcf/d of natural gas. The Company plans to reach these production levels by the end of the first quarter. For 2002, the Company has hedged approximately 60 percent of its projected oil production and 70 percent of its projected gas production through fixed price or financial derivative contracts. Consequently, cash flow for the year is substantially protected against commodity price volatilities. Using the above production levels and pricing assumptions of US\$21.50/bbl for WTI oil, US\$6.25/bbl for Lloyd Blend differentials, CAN\$3.60/mcf for gas field prices, \$0.63 for exchange rate and interest rates at current levels, cash flow for 2002 is projected to be \$158 million or \$3.03 per share. A capital budget of

OGY, representing 96.5 percent of issued and outstanding shares are tendered in response to Baytex's offer to purchase. ■ **May 30, 2001** Baytex acquires Triumph Energy Corporation as 33.04 million common shares of Triumph, representing 97.2 percent of the issued and outstanding shares, are tendered in response to Baytex's offer to purchase. ■ **Dec 18, 2001** Baytex announces agreements have been reached on a series of transactions which will

\$120 million is planned for the year, with approximately 45 percent to 50 percent allocated to heavy oil activities. The Company's financial position will remain strong through 2002. Nearly two-thirds of the Company's projected year-end total debt would be in the form of 10-year subordinated notes and approximately 90 percent of total debt would be represented by long-term notes. Bank borrowings are expected to account for only five percent of total debt, resulting in excellent financial stability and flexibility for the Company.

Today, Baytex represents a company with great strength and opportunities. It is the purest heavy oil play amongst conventional exploration and production companies in Canada. As seen in the cyclical pattern established since deregulation, heavy oil appears to be back in a normal pricing environment which has been both long-lasting and economically rewarding for low cost producers such as Baytex. The Company also has the best in-house inventory for natural gas exploration and development opportunities in its history. Baytex believes in the benefits of a balanced production mix and the profitable long-term prospects of growing its natural gas production in North America.

On behalf of its Board of Directors, management would like to thank the Company's shareholders for their continued support and its employees for their dedication over the past year. Baytex has a diverse portfolio of debt instruments which translates into excellent stability and flexibility and allows the Company to execute its operating strategies through unfavourable economic cycles. This financial flexibility combined with a diverse portfolio of growth prospects should translate into a very exciting 2002, where we are committed to delivering superior returns to our shareholders.

On behalf of the Board of Directors



Dale O. Shwed

President and Chief Executive Officer

March 18, 2002

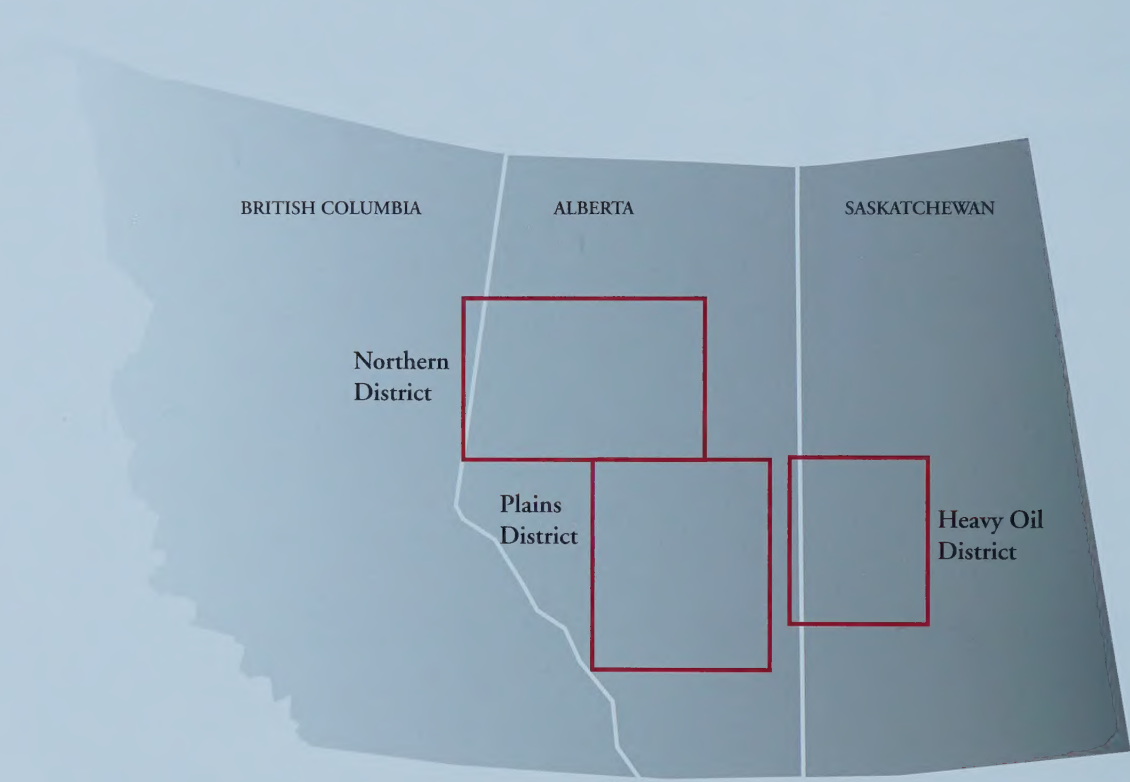
provide the Company with total proceeds of \$120 million, all of which will be applied against existing bank loans. In addition, interest rate swaps that exchange fixed rate coupon payments to floating rates have the potential, under current interest rates, to realize a \$10 million interest savings per annum for Baytex.



Left to right: Bill Krepps, *Manager, Heavy Oil Production*
Ryan Chong, *Manager, Acquisitions and Corporate Development*

AREAS OF OPERATION

DURING 2001, WE FURTHER FOCUSED OUR OPERATIONS IN OUR MAIN GEOGRAPHICAL REGIONS BY REORGANIZING OUR TECHNICAL STAFF INTO THREE DISTRICTS. THESE DISTRICTS ARE FOCUSED ON TAKING ADVANTAGE OF THE VAST AMOUNT OF TECHNICAL AND OPERATING INFORMATION THAT WE HAVE IN OUR CORE AREAS TO EVALUATE POTENTIAL PROSPECTS IN THESE AREAS, IDENTIFY STRATEGIC ACQUISITIONS IN THE AREAS AND TO DEVELOP AND OPERATE OUR EXISTING PROPERTIES IN AN EFFICIENT AND LOW-COST MANNER.



HEAVY OIL DISTRICT

Our Heavy Oil District makes up the largest component of Baytex's current production and reserve base. In 2001, Baytex produced 26,533 bbls/d of heavy oil, 368 bbls/d of light oil and 11.5 mmcf/d of natural gas from this district. It includes operations in our main areas at Tangleflags, Lashburn, Carruthers, and Poundmaker in Saskatchewan and Cold Lake in Alberta.

HEAVY OIL DISTRICT

PRODUCTION (Mar 2002)

- 23,500 bbls/d
- 7.5 mmcf/d

UNDEVELOPED LANDHOLDINGS

- 278,002 acres
- 90% average WI

NORTHEAST ALBERTA

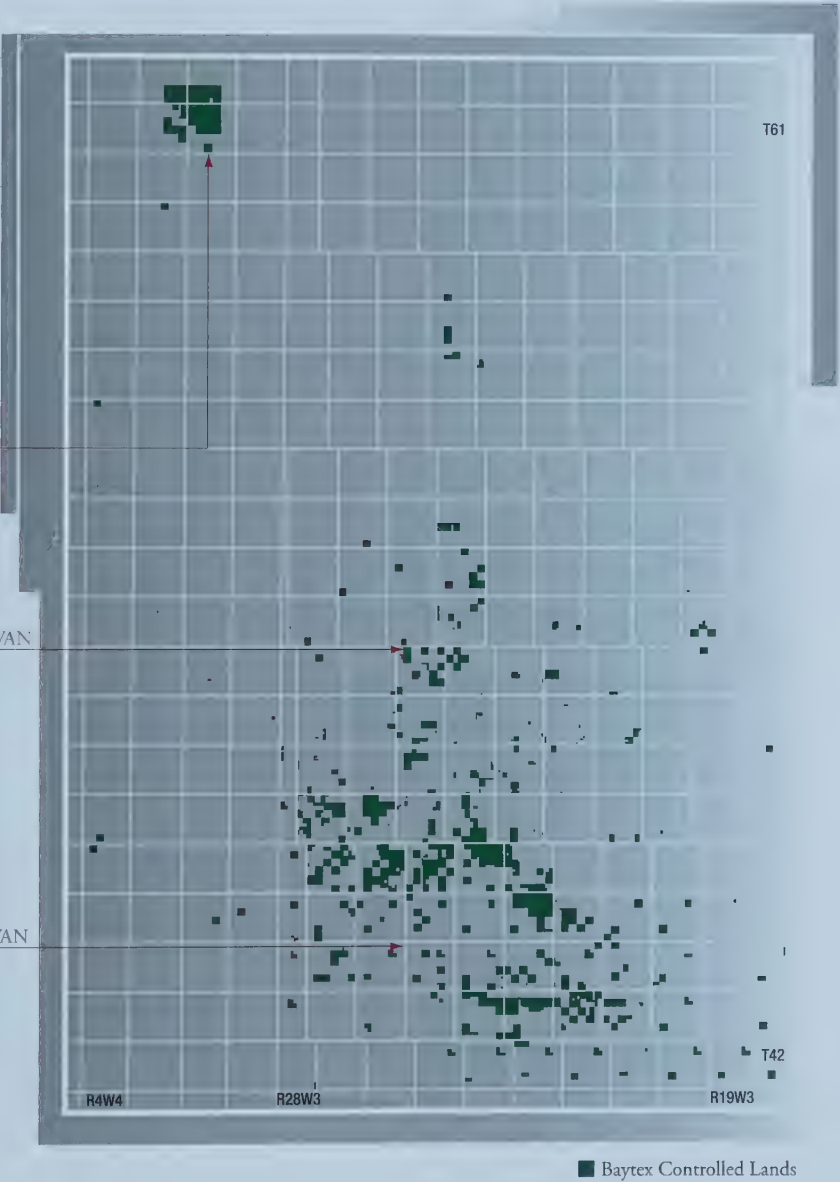
Cold Lake
Wolf Lake

NORTHERN SASKATCHEWAN

Buzzard
Greenstreet
Lashburn
Maidstone
Marshall
Tangleflags

SOUTHERN SASKATCHEWAN

Baldwinton
Carruthers
Cutknife
Marsden
Neilburg
Unwin/Epping



Our heavy oil operations consist mainly of cold conventional production from the Cummings, Colony, McLaren, Waseca, Sparky and Lloydminster formations. Production focuses on vertical and slant wells using progressive cavity pumping to generate initially large volumes of sand and oil. The removal of sand from the reservoir creates “worm holes” that leads to increased oil production. Production from these wells usually averages between 40 and 100 bbls/d of sour, lower gravity crude ranging from 12 to 18 API. Once production is in the tank, oil is separated from sand and then trucked or pipelined to markets in Canada and the United States for upgrading into a lighter grade of crude or refined into petroleum products.

In 2001, the Company drilled 58 successful heavy oil wells throughout our operating areas in west central Saskatchewan and in our newly acquired area at Cold Lake, Alberta. Heavy oil drilling was curtailed in the latter part of 2001 as oil prices declined significantly and heavy oil differentials remained at their widest levels ever. The Company also reduced spending on regular well maintenance and shut-in approximately 3,000 bbls/d of heavy oil production as a result of the poor economics.

The year 2002 has brought a brighter outlook for our Heavy Oil District. Oil prices have strengthened throughout the first quarter with WTI reaching US\$25.00/bbl by mid-March. Heavy oil differentials have also dramatically improved from US\$10.00/bbl for Lloyd Blend at Hardisty in the fourth quarter of 2001 to around US\$5.00 in March 2002. With the economics for heavy oil improving, the Company has planned for the drilling of 110 heavy oil wells in 2002. This drilling will be focused in our Cold Lake and Tangleflags areas targeting multi-zone conventional heavy oil production. Since the beginning of January, we have also been reactivating the production that had been shut-in during the fourth quarter of last year.

Baytex continues to pursue new heavy oil opportunities and is continually adding to its drilling inventory to underpin future production growth. We are also actively participating in a research and development project for enhanced recovery through our VAPEX pilot project. This vapor extraction process, if successful, could significantly increase the Company's heavy oil production and reserves recovery factors from existing oil pools.

PLAINS DISTRICT

The Plains District is the Company's largest natural gas producing area. Average production in 2001 includes 35.5 mmcf/d of natural gas and 3,721 bbls/d of oil and natural gas liquids. Natural gas production is from several areas across central Alberta, the most significant ones being Bon Accord, Ferrier, Leahurst, O'Chiese and Richdale. The district's current light oil production comes from Sounding Lake, a property acquired in the OGY transaction, and from Bon Accord in central Alberta.

The Plains District realized the largest benefit from our 2001 corporate acquisitions. The acquisition of OGY added significant natural gas development potential in the Richdale and Viking areas. The Richdale area, with its Second White Specks and Lower Mannville gas pools, complements our existing assets at Leahurst/Donalda. Subsequent to this acquisition, the Company drilled 15 successful Second White Specks gas wells in the area. Current production from the Richdale area is in excess of 6.8 mmcf/d. We plan to drill additional Second White Specks wells in the area over the next year as well as several lower Mannville targets.

At Viking, Baytex drilled five successful lower Mannville and Basal Belly River gas wells in 2001 with production increasing to 5.1 mmcf/d currently. In the first quarter of 2002, we conducted a 2D seismic program to evaluate the southern portion of our holdings in the area. The Company holds in excess of 25,000 acres of undeveloped land in the Viking area.

The acquisition of Triumph in May added significant production and development potential in the Ferrier area, where the drilling targets are long life, multi-zone liquids-rich natural gas reserves. Subsequent to the acquisition, the Company drilled seven natural gas wells in this area in 2001. These wells are capable of production from the Cretaceous Ostracod, Ellerslie and Rock Creek formations. Current production from this area includes 10.0 mmcf/d of natural gas and 600 bbls/d of natural gas liquids. In 2002, we plan to drill 10 to 12 development wells in this area.

PLAINS DISTRICT

PRODUCTION (Mar 2002)

- 1,800 bbls/d
- 45.5 mmcf/d

UNDEVELOPED LANDHOLDINGS

- 273,031 acres
- 71% average WI

PLAINS GROUP

- Bon Accord
- Brazeau River/O'Chiese
- Drumheller
- Ferrier
- Lanaway
- Leahurst/Donalda
- Mapleglen/Leo
- Richdale
- Viking/Kinsella
- Wimbourne



We also acquired operations in the O'Chiese area through the Triumph transaction, where the target is natural gas from the Cretaceous Ostracod formation. We drilled two wells in 2001 resulting in one oil well and one natural gas well. To date in 2002, two additional wells have been drilled adding two natural gas wells. Natural gas wells in this area typically result in stabilized production between 1.0 and 2.0 mmcf/d.

We are focused on improving operational efficiencies within the new areas that the Company acquired in 2001. Efforts continue to develop new plays over the District's 273,000 net acres of undeveloped land with particular focus on opportunities within and adjacent to our existing core areas.

NORTHERN DISTRICT

Our Northern District is situated in northwestern Alberta and northeastern B.C. and includes all of the Company's operating areas north of Township 50 and west of the fifth meridian. This area holds Baytex's greatest potential for high impact natural gas exploration success. While the area does not hold a large percentage of the Company's current producing assets, this District has over 840,000 acres of land including 588,800 acres of undeveloped land with an average working interest of 85 percent.

Production from the area in 2001 averaged 23.8 mmcf/d of natural gas and 1,063 bbls/d of light oil. Light oil production in the district comes mainly from the Slave Point and Granite Wash formations in the Red Earth area, where two successful oil wells were drilled in 2001 and one oil well was drilled in the first quarter of 2002.

Natural gas production in the Northern District is produced mainly from the seven gas Bluesky formation in the Goodfish/Lafond and Darwin/Nina areas. Baytex drilled seven gas wells in 2001 and an additional eight gas wells in the first quarter of 2002. We continually evaluate new prospects in these areas which had a low average operating cost of \$0.43/mcf in 2001 due to our ownership of an extensive pipeline infrastructure and natural gas processing plants.

Baytex conducts the majority of its high impact exploration activities in the Northern District. At Dawson/Tangent, we drilled two Cretaceous natural gas wells in the first quarter of 2002. These wells are planned to be tied-in and on production early in the second quarter and should add an additional 3.5 mmcf/d of natural gas production to the Company by the end of the second quarter. We are conducting a 2D seismic program in the area to identify additional locations to be drilled in the second half of 2002. Also at Dawson/Tangent, a 3D seismic program is being conducted to identify oil targets in the Slave Point formation. These targets can result in wells that have up to 500,000 bbls of recoverable reserves and produce at rates ranging from 250 bbls/d to 1,000 bbls/d.

Exploration is also continuing on Baytex's lands in the Hamburg/Chinchaga area. In the first quarter of 2002, a natural gas well was drilled at Chinchaga into the Slave Point formation. This well is currently being tested and may result in follow-up locations to be drilled in the latter half of 2002. Wells in this area are capable of producing up to 80 mmcf/d and may have recoverable reserves of over 100 bcf.

The Company holds 53,000 net undeveloped acres at Petitot in northwest Alberta where it is exploring for Slave Point natural gas targets. These wells can yield reserves up to 15 bcf and produce at rates up to 15 mmcf/d. Current plans are to drill our first exploration well in this area during the 2002/2003 winter season.

NORTHERN DISTRICT

PRODUCTION (Mar 2002)

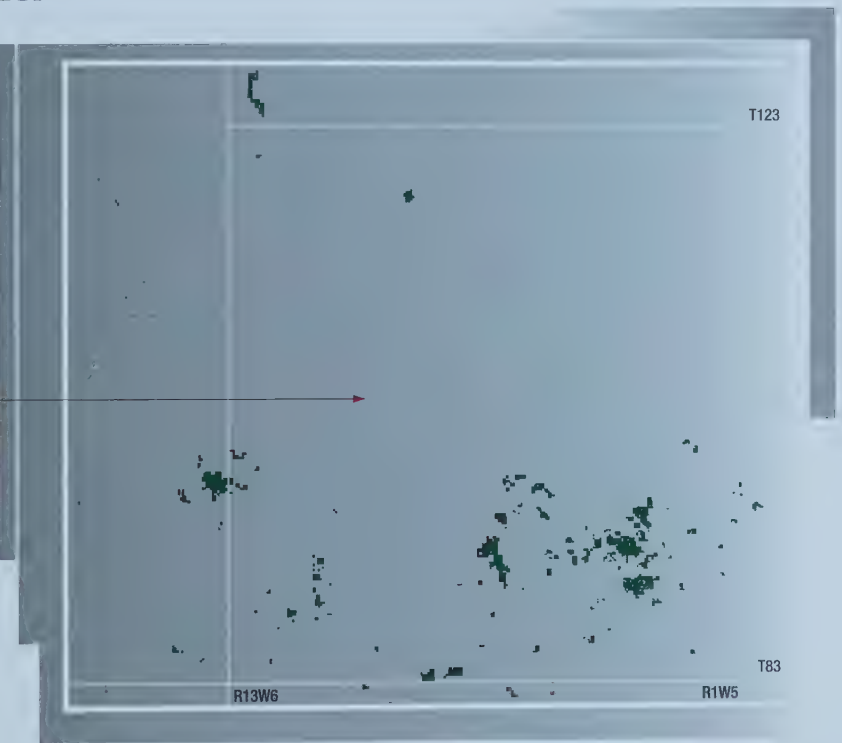
- 1,000 bbls/d
- 22.0 mmcf/d

UNDEVELOPED LANDHOLDINGS

- 588,772 acres
- 85% average WI

NORTHERN GROUP

- Dawson
- Goodfish/Lafond
- Hamburg/Ladyfern
- Nina/Gardner
- Petitot
- Red Earth
- West Liege
- Woking
- Worsley



■ Baytex Controlled Lands

OPERATIONS REVIEW

LAND

Baytex continued to add to its already significant undeveloped land base in 2001. As a result of corporate acquisitions, focused Crown and freehold acquisition programs, as well as farmin and other arrangements, Baytex's undeveloped land holdings grew by 298,723 gross (197,994 net) acres to 1,385,492 gross (1,139,805 net) acres, representing a 27 percent increase over year-end 2000. The Company's average working interest remains very high at 82 percent.

The Company spent \$6.6 million at Crown land sales in 2001 to acquire 85,520 net acres. Through strategic freehold leasing programs, Baytex secured another 82,643 net acres at a cost of \$888,000. Approximately 80 percent of acreage growth in 2001 was achieved through selective acquisitions, with the remaining 20 percent attributable to those acquired through corporate acquisitions.

Charter Land Services Ltd. has provided an independent evaluation of Baytex's undeveloped acreage as at December 31, 2001 and has attributed a replacement cost value of \$89.5 million to our holdings, which represents a 30 percent increase from the year-end 2000 evaluation of \$68.9 million.

The following table summarizes the undeveloped acreage owned by Baytex as of December 31, 2001. Undeveloped acreage means acreage on which we do not have a productive well and includes exploratory acreage.

Undeveloped Land Summary

(acres)	2001			2000		
	Gross	Net	Average Interest	Gross	Net	Average Interest
Northern District	689,458	588,772	85%	697,307	595,287	85%
Plains District	385,585	273,031	71%	219,930	181,367	82%
Heavy Oil District	310,449	278,002	90%	169,532	165,157	97%
Total	1,385,492	1,139,805	82%	1,086,769	941,811	87%
Value	\$89.5 million			\$ 68.9 million		

DRILLING ACTIVITY

The number of exploratory and development wells drilled by Baytex in 2001 and 2000 are summarized below:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
2001						
Crude oil	1	1	62	57.2	63	58.2
Natural gas	7	5	74	65.3	81	70.3
Service	—	—	3	2.4	3	2.4
Dry and abandoned	8	7.3	24	21.4	32	28.7
Total	16	13.3	163	146.3	179	159.6
Success rate (%)	50	45	85	85	82	82
Average working interest (%)		83		90		89
2000						
Crude oil	18	18.0	249	245.9	267	263.9
Natural gas	7	7.0	21	17.3	28	24.3
Service	—	—	4	4.0	4	4.0
Dry and abandoned	11	9.4	12	11.0	23	20.4
Total	36	34.4	286	278.2	322	312.6
Success rate (%)	69	73	96	96	93	93
Average working interest (%)		96		97		97

OIL AND GAS RESERVES

Outtrim Szabo Associates Ltd., independent oil and gas reservoir engineers, prepared a report evaluating our crude oil and natural gas reserves as of December 31, 2001. In connection with their review, Baytex provided Outtrim with land data, well information, geological information, reservoir studies, estimates of onstream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Outtrim also obtained other engineering, geological or economic data from public records, other operators and their non-confidential files.

Oil and Gas Reserves

December 31, 2001	Reserves (before royalties)		Present worth of reserves discounted at		
	Oil & Liquids (mbbls)	Gas (mmcf)	0%	10%	15%
			(\$ thousands)		
Proved developed					
Producing	31,944	91,605	614,388	449,891	401,249
Non-producing	39,261	30,731	482,586	245,118	193,958
Proved undeveloped	39,016	12,317	432,036	233,031	182,098
Total proved	110,221	134,653	1,529,010	928,040	777,305
Probable	52,334	42,767	730,326	354,567	270,938
Total proved and probable	162,555	177,420	2,259,336	1,282,607	1,048,243

Pricing Assumptions

	WTI at Cushing, Oklahoma	Light oil at Edmonton	Baytex Heavy oil	Alberta spot gas price
	(US\$/bbl)	(CAN\$/bbl)	(CAN\$/bbl)	(CAN\$/mcf)
2002	20.50	31.13	17.56	4.12
2003	20.81	31.09	19.10	4.39
2004	21.12	31.05	20.58	4.43
2005	21.44	31.02	21.54	4.42
2006	21.76	31.48	22.01	4.47

Reserve Reconciliation

	Crude oil and NGLs (mbbls)			Natural gas (mmcf)		
	Proved	Probable	Total	Proved	Probable	Total
December 31, 1999	56,420	37,055	93,475	103,947	47,604	151,551
Discoveries and extensions	17,684	2,108	19,792	9,727	3,074	12,801
Acquisitions	37,700	10,905	48,605	10,767	—	10,767
Dispositions	(213)	(109)	(322)	(3,735)	(4,650)	(8,385)
Revisions of prior estimates	2,256	(1,921)	335	(1,556)	(15,826)	(17,382)
Production	(8,825)	—	(8,825)	(21,102)	—	(21,102)
December 31, 2000	105,022	48,038	153,060	98,048	30,202	128,250
Discoveries and extensions	11,049	4,054	15,103	19,705	3,421	23,126
Acquisitions	12,832	7,241	20,073	61,162	18,050	79,212
Dispositions	(7,593)	(5,809)	(13,402)	(6,527)	(1,725)	(8,252)
Revisions of prior estimates	477	(1,190)	(713)	(11,887)	(7,181)	(19,068)
Production	(11,566)	—	(11,566)	(25,848)	—	(25,848)
December 31, 2001	110,221	52,334	162,555	134,653	42,767	177,420

Reserve Life Index

December 31, 2001	Q4 – 2001 production	Total proved	Proved and probable
Crude oil and NGLs (bbls/d)		30,336	14.7
Natural gas (mmcf/d)		4.9	6.4
Oil equivalent (boe/d)		8.5	12.2

Net Asset Value

December 31, 2001 (thousands)	DCF 10%	DCF 15%
Established (proved plus 50 percent probable) reserves	\$ 1,105,324	\$ 912,774
Undeveloped land	89,519	89,519
Long-term debt and working capital	(425,956)	(425,956)
Stock option proceeds	27,657	27,657
Net asset value	\$ 796,544	\$ 603,994
Diluted shares outstanding	56,476	56,476
Net asset value per diluted share	\$ 14.10	\$ 10.70

Notes:

(1) Working capital excludes \$46.9 million of properties held for sale, classified as current assets as at December 31, 2001, which sales were completed in the first quarter of 2002.

(2) The Company had approximately \$525 million in available future tax deductions as at December 31, 2001, which value is not included in the above net asset value calculation.

Investment Efficiency

Baytex's capital program for 2001 totaled \$376.1 million and included the acquisition of Triumph Energy Corporation for \$170.5 million, the acquisition of OGY Petroleums Ltd. for \$78.6 million and two acquisitions of heavy oil properties for a combined \$40.5 million. During the fourth quarter, \$52.6 million of light oil and heavy oil property dispositions were completed. The Company's exploration and development program for the year totaled \$136.1 million. Baytex's 2001 finding and development costs were higher than its historical levels as the 2001 capital program was dedicated to the additions of natural gas and light oil reserves. Specifically, this program added 68.7 bcf of established gas reserves, equivalent to 61 percent of the gas reserves at year-end 2000. The recycle ratios of the Company were negatively affected by a prolonged period of wide heavy oil differentials which significantly impaired corporate cash flow. This is most evident in 2001 as heavy oil accounted for 61 percent of total production and differentials were the widest on record. Baytex is confident that as heavy oil differentials recover to normal levels, the long-term economics and benefits of its asset base will be fully realized.

The efficiency of the Company's capital program for the year 2001 and the three-year period from 1999 to 2001 is summarized as follows:

	2001	1999-2001 3-year average
Capital expenditures (thousands)	\$ 376,085	\$ 278,418
Finding and development (\$/boe)		
Proved	13.84	8.71
Proved + 1/2 probable	12.38	7.76
Proved + probable	11.21	7.01
Cash flow netbacks (\$/boe)	9.07	10.26
Reserve recycle ratio		
Proved	0.7	1.2
Proved + 1/2 probable	0.7	1.3
Proved + probable	0.8	1.5
Reserve replacement ratio		
Proved	1.7	2.7
Proved + 1/2 probable	1.9	3.0
Proved + probable	2.1	3.4

MARKETING

CRUDE OIL

World crude oil prices remained very buoyant in 2001, despite the economic slowdown after September 11. Benchmark WTI crude oil prices averaged US\$25.90/bbl in 2001, down from US\$30.20 in 2000, but still significantly higher than the 10-year average of US\$20.70. Prices hovered around US\$28.00/bbl for the January to September 2001 period, but fourth quarter prices fell into the US\$20.00 range as reduced air travel and industrial activities caused demand to plummet.

OPEC cooperation was the primary reason for strong prices in 2001. OPEC has been successful in maintaining prices within their preferred range through supply constraints. This effort was supplemented in late 2001 when non-OPEC producers Russia, Mexico, and Norway agreed to reduce exports to bring supplies in line with demand.

Baytex's conventional crude oil and natural gas liquids prices averaged \$33.65/bbl in 2001, down from \$40.23 in 2000. This reduction was reflective of world crude oil prices.

Heavy oil prices did not enjoy the benefit of strong world prices as the differential between light and heavy crude oil prices was the widest since price deregulation in 1985. The differential between WTI and Lloyd Blend prices averaged US\$10.69/bbl in 2001 (42 percent of WTI), up from US\$8.21/bbl in 2000 (27 percent of WTI), and significantly higher than the 16-year average of US\$5.83 (29 percent of WTI) since deregulation. Production cutbacks have aided heavy oil prices as producing countries remove their lowest margin barrels from the market, thus tightening the differential.

Canadian heavy oil prices were dramatically impacted by refinery problems in 2001. The Citgo refinery near Lemont, Illinois experienced a fire in its main crude processing unit in August, thus reducing demand for Canadian heavy and sour crudes by over 100,000 bbls/d. The fall in demand forced heavy oil volumes into alternate markets and widened differentials substantially. The refinery has been processing some Canadian heavy oil in a reconfigured mode while repairs are being conducted, and is scheduled to return to normal operations in April 2002. Differentials in the first quarter of 2002 averaged US\$6.00/bbl and are expected to fall further as seasonal increase in asphalt demand and reduced supplies serve to tighten the market.

Baytex's heavy oil prices averaged \$16.69/bbl in 2001 compared to \$26.54 in 2000. Increased heavy oil differentials and lower world prices contributed to the drop.

NATURAL GAS

Natural gas prices were very strong in 2001, particularly in the first half as demand for gas-fired electricity pushed prices up to unprecedented levels. Gas prices in the United States, represented by the NYMEX futures contract, averaged US\$4.38/mcf in 2001, up from US\$3.91 in 2000. Prices retreated in the latter part of the year as reduced industrial demand, coupled with warmer than usual winter weather across North America, left storage above historical levels. Canadian gas prices are closely linked to US prices as recent additions to export capacity have allowed Canadian gas to compete in US markets.

Baytex received an average of \$4.42/mcf for 2001 gas sales, up from \$4.01 in 2000.

ENVIRONMENT AND SAFETY

Protection of the environment is one of the key operating goals of Baytex. Senior management is actively involved in the effort to ensure continual improvement and cooperation throughout the Company. Our operational planning accommodates the increased lead time and costs associated with satisfying environmental concerns.

Baytex's environmental operating standards are based on pertinent provincial and federal regulations and guidelines to ensure due diligence and proper documentation of all facets of environmental operations. These standards are, at a minimum, as stringent as current regulatory standards and, in many instances, exceed them. Regulatory changes are monitored so new requirements can be integrated into operations as soon as changes occur.

Employees receive necessary training to meet environmental operating standards. Reporting and information management systems ensure that appropriate personnel are informed of environmental issues and can respond efficiently.

Baytex has a continuing program of site abandonment, clean up and restoration which eliminates potential environmental problems in a timely manner. Environmental compliance of operating facilities is monitored regularly. Liability assessments of acquisitions and divestitures ensure that any environmental costs are properly assessed. Baytex makes adequate provisions in the financial statements for these costs.

In all areas of our activities, the Company strives to operate safely with sensitivity to the environment and the needs of local residents and employees.



MANAGEMENT'S DISCUSSION AND ANALYSIS

The following discussion and analysis should be read in conjunction with the Company's audited consolidated financial statements for the fiscal years ended December 31, 2001 and 2000. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

OVERVIEW

Baytex completed a number of significant transactions in 2001 that have enhanced the long-term prospects of the Company. These transactions include:

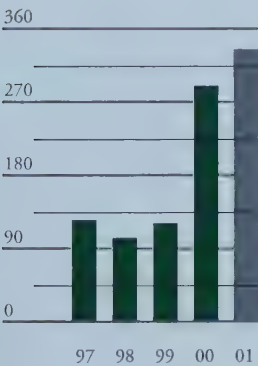
- In February 2001, we completed an offering of 10-year US\$150 million, 10.5 percent senior subordinated notes. This financing created substantial additional credit capacity for the Company and improved the long-term stability of our capital structure.
- In May 2001, we acquired OGY Petroleums Ltd. for a total consideration of \$78.6 million consisting of 1.2 million Baytex shares, \$53.8 million cash and the assumption of \$10.8 million of debt.
- In June 2001, we acquired Triumph Energy Corporation for a total consideration of \$170.5 million consisting of 4.9 million Baytex shares, \$93.6 million cash and the assumption of \$22.8 million of debt.
- In the second quarter of 2001, we completed two acquisitions of heavy oil properties for a combined \$40.5 million.

Production

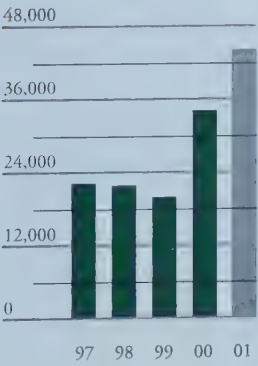
The Company's average production for fiscal 2001 increased by 29 percent to 43,488 boe/d from 33,721 boe/d for fiscal 2000.

Light oil production increased 25 percent to 5,152 bbls/d during 2001 from 4,107 bbls/d in 2000. The increase was due to the acquisitions of OGY and Triumph in the second quarter of 2001.

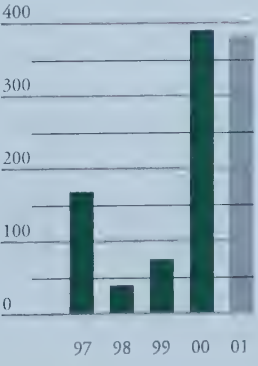
REVENUE
(\$millions)



PRODUCTION
(boe/d)



NET CAPITAL
EXPENDITURES
(\$millions)



Heavy oil production during 2001 increased by 33 percent to 26,533 bbls/d from 20,005 bbls/d during fiscal 2000 due to the Company's successful development drilling program and property acquisitions that were completed in the second quarter of 2001.

Overall natural gas production for 2001 increased by 23 percent to 70.8 mmcf/d compared to 57.7 mmcf/d for the prior year due to the OGY and Triumph acquisitions and a successful drilling program in our Northern and Plains Districts.

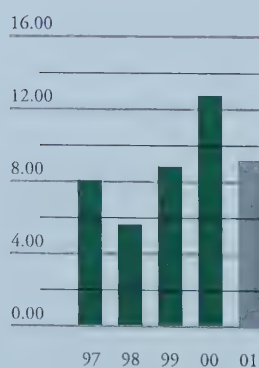
Production by Area

	Conventional Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2001				
Heavy Oil District	368	26,533	11.5	28,813
Plains District	3,721	–	35.5	9,192
Northern District	1,063	–	23.8	5,483
Total Production	5,152	26,533	70.8	43,488
2000				
Heavy Oil District	348	20,005	8.8	21,814
Plains District	1,985	–	22.4	5,721
Northern District	1,774	–	26.5	6,186
Total Production	4,107	20,005	57.7	33,721

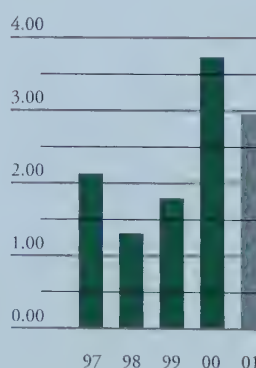
REVENUE

Petroleum and natural gas sales for 2001 increased by 15 percent to \$329.7 million from \$286.2 million for fiscal 2000. Benchmark WTI crude oil averaged US\$25.90/bbl for 2001, representing a 14 percent decrease over the US\$30.20 for 2000. Heavy oil differentials increased from 2000 with Baytex's heavy oil receiving 43 percent of the Canadian par crude price during fiscal 2001 compared to 60 percent in 2000. Natural gas prices were 10 percent higher in 2001 averaging \$4.42/mcf compared to \$4.01 during fiscal 2000. This increase was the result of record high prices in the first quarter of 2001. Overall, after accounting for losses from financial derivative contracts, Baytex averaged \$20.77/boe for 2001 production, a 10 percent decrease from \$23.19 received in the prior year.

CASH FLOW NETBACKS
(\$/boe)



CASH FLOW PER SHARE
(\$/share)



Gross Revenue Analysis

	2001		2000	
	\$000s	\$/Unit	\$000s	\$/Unit
Oil revenue (barrels)				
Light oil	63,288	33.65	60,475	40.23
Heavy oil	161,681	16.69	194,328	26.54
Derivative contract loss	(9,513)	(0.82)	(53,177)	(6.03)
Total oil revenue	215,456	18.63	201,626	22.85
Natural gas revenue (mcf)	114,244	4.42	84,600	4.01
Total revenue (boe @ 6:1)	329,700	20.77	286,226	23.19

ROYALTIES

Total royalties increased 15 percent to \$57.8 million for fiscal 2001 from \$50.4 million for the prior year due to higher overall sales revenue. The average royalty rate for 2001 was 17.0 percent of sales compared to 14.9 percent of sales for fiscal 2000. In 2001, royalties were 19.1 percent of sales for light oil (2000 – 18.7 percent), 10.6 percent for heavy oil (2000 – 10.2 percent) and 25.1 percent for natural gas (2000 – 22.9 percent).

OPERATING EXPENSES

Operating expenses for 2001 increased 55 percent to \$83.4 million from \$53.8 million during the previous year. This increase is attributable to an increase in overall production as well as increased costs of operations due to inflation brought on by high industry activity levels. For 2001, operating expenses by product were higher than the prior year at \$6.82/bbl of light oil, \$5.59/bbl of heavy oil and \$0.64/mcf of natural gas. In comparison, operating expenses by product for 2000 were \$5.29/bbl of light oil, \$4.91/bbl of heavy oil and \$0.47/mcf of natural gas. Overall operating expenses increased 21 percent to \$5.26/boe during 2001 from \$4.36 for 2000.

Operating Netbacks

	Conventional oil & NGLs (\$/bbl)		Heavy Oil (\$/bbl)		Total Oil & NGLs (\$/bbl)		Natural Gas (\$/mcf)		Oil Equivalent (\$/boe)	
	2001	2000	2001	2000	2001	2000	2001	2000	2001	2000
Sales price	33.65	40.23	16.69	26.54	19.45	28.87	4.42	4.01	21.37	27.50
Royalties	(6.44)	(7.51)	(1.77)	(2.71)	(2.53)	(3.53)	(1.11)	(0.91)	(3.64)	(4.09)
Operating costs	(6.82)	(5.29)	(5.59)	(4.91)	(5.79)	(4.97)	(0.64)	(0.47)	(5.26)	(4.36)
Net revenue	20.39	27.43	9.33	18.92	11.13	20.37	2.67	2.63	12.47	19.05

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses, after capitalization, increased to \$5.3 million for 2001 compared to \$4.3 million for 2000 as a result of the increase in the size of the Company's operations. On a per unit of production basis, these expenses decreased during 2001 to \$0.33/boe from \$0.35 in 2000. In accordance with the full cost accounting policy, \$5.3 million of expenses relating to exploration and development activities were capitalized in 2001 compared to \$4.3 million in 2000.

General and Administrative Expenses

(\$ thousands)	2001	2000
Gross expense	16,504	14,660
Operator's recoveries	(5,980)	(5,998)
Subtotal	10,524	8,662
Capitalized expense	(5,262)	(4,331)
Net expense	5,262	4,331

INTEREST EXPENSE

Interest expense on long-term debt increased to \$33.9 million for the year ended December 31, 2001 from \$13.8 million for last year. This increase is due to additional debt incurred primarily for acquisition purposes. Also, in February 2001, the Company issued the 10.5 percent US\$150 million senior subordinated notes. Average month-end long-term debt was \$388.8 million for 2001 compared to \$182.5 million for 2000.

DEPLETION, DEPRECIATION AND AMORTIZATION

Depletion, depreciation and amortization prior to the ceiling test considerations increased to \$132.9 million for 2001 compared to \$84.6 million for 2000. This increase is due to the increase in production and the acquisitions of OGY and Triumph, for which ascribed book values were increased by the estimated future tax liability associated with the excess of book value over the tax value of these assets. On a unit of production basis, the provision for 2001 was \$8.37/boe compared to \$6.85 for last year.

Beginning in fiscal 2001, oil and gas companies in Canada using the full cost method of accounting are required to perform a ceiling test on their book value at the end of each fiscal quarter using product prices at the end of the reporting period. Based on the extremely wide heavy oil differentials at year-end 2001, Baytex incurred a \$131.3 million ceiling test write-down (net of \$103.2 million of future income taxes). The arbitrary nature of the ceiling test is particularly punitive to Baytex due to the high component of heavy oil in its reserves. The write-down is the result of a temporary and severe drop in heavy oil price at year-end, as no write-down was required at the end of each of the first three quarters in 2001 and also no write-down would have been required had the ceiling test been conducted with January 2002 prices. Furthermore, this write-down is a non-cash charge to the net book value of the Company's oil and gas assets. It does not reflect the fair value of these assets and has no significant impact on Baytex's capital structure nor its debt covenant requirements. It will improve future earnings for the Company as depletion and depreciation rates are reduced.

SITE RESTORATION COSTS

Site restoration costs for 2001 increased to \$3.9 million from \$3.4 million last year due to higher production. On a unit of production basis, the provision for 2001 was \$0.22/boe compared to \$0.25 for the previous year.

INCOME TAXES

Current tax expenses were \$7.1 million for 2001 compared to \$8.5 million in 2000. The current tax expenses are comprised of \$6.1 million of Saskatchewan Capital Tax and \$1.0 million of Large Corporation Tax, compared to \$7.0 million and \$1.5 million, respectively, for the prior year. Saskatchewan Capital Tax declined as a result of lower commodity prices and the Large Corporation Tax decrease results from a reduction in the Company's year-end taxable capital due to the ceiling test write-down.

The 2001 provision for future income taxes, prior to ceiling test considerations, was \$2.6 million compared to \$23.5 million in 2000. This reduction was the result of lower corporate earnings in 2001 due to a decline in commodity prices. Future income taxes for 2001 also included a \$103.2 million recovery associated with the ceiling test write-down.

Canadian Tax Pools

(\$ thousands)	December 31, 2001
Cumulative Canadian Exploration Expense	120,000
Cumulative Canadian Development Expense	138,000
Cumulative Canadian Oil and Gas Property Expense	72,000
Undepreciated Capital Cost	167,000
Other available deductions	28,000
Total tax pools	525,000

CASH FLOW FROM OPERATIONS

Cash flow from operations for the year ended December 31, 2001 decreased seven percent to \$144.1 million from \$155.3 million for the previous year, as a result of lower field netbacks and a higher interest expense. Field netbacks were lower than the prior year due to lower oil prices and higher unit operating expenses. On a barrel of oil equivalent basis, cash flow netbacks were \$9.07 for 2001 compared to \$12.58 for 2000.

Cash Flow Netbacks

	2001		2000	
	\$/boe	Percent	\$/boe	Percent
Production revenue	21.37	100	27.50	100
Derivative contract loss	(0.60)	(3)	(4.31)	(16)
Net royalties	(3.64)	(17)	(4.09)	(15)
Operating expenses	(5.26)	(25)	(4.36)	(16)
Field netbacks	11.87	55	14.74	53
General and administrative expenses	(0.33)	(1)	(0.35)	(1)
Interest expense	(2.02)	(9)	(1.12)	(4)
Current income taxes	(0.45)	(2)	(0.69)	(2)
Cash flow netbacks	9.07	43	12.58	46

CAPITAL EXPENDITURES

Overall net capital expenditures decreased two percent from \$384.9 million in 2000 to \$376.1 million in 2001. The increase in gross spending during 2001 as a result of the acquisition of OGY and Triumph was offset by a fourth quarter disposition program which resulted in \$52 million of dispositions closing prior to December 31, 2001. Total exploration and development expenditures decreased to \$136.1 million for 2001 compared to \$170.8 million for 2000 as a result of reduced development spending on heavy oil projects.

Capital Expenditures

(\$ thousands)	2001	2000
Land	11,494	18,481
Seismic	7,242	9,186
Drilling and completions	71,928	94,069
Equipment	37,438	42,999
Other	8,019	6,052
Total exploration and development	136,121	170,787
Corporate acquisitions	249,152	221,754
Property acquisitions	53,394	1,869
Dispositions	(62,582)	(9,553)
Net capital expenditures	376,085	384,857

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2001, total net debt (including working capital) was \$379.1 million compared to \$256.3 million at December 31, 2000. This increase during the year was the result of the addition of the US\$150 million senior subordinated notes that were used primarily to finance the acquisitions of OGY and Triumph.

The Company's debt structure consists of three main components. The first component is the Company's bank facilities, which at December 31, 2001 had a total commitment of \$110 million, of which \$73.8 million was drawn. This commitment is set by the banking syndicate based on their assigned value of the Company's petroleum and natural gas reserves through periodic reviews. The bank facilities were revised to \$85 million in February 2002 after the completion of the asset divestiture program.

The second component is the US\$57 million senior secured notes due in November 2004. These notes are governed by certain financial covenants measured at the end of each fiscal quarter. These covenants were met throughout 2001. The principal covenants are: (i) consolidated tangible net worth not to be less than \$200 million, excluding accounting ceiling test write-down (such net worth was \$488.2 million as at December 31, 2001); (ii) consolidated total debt not to exceed 300 percent of consolidated cash flow (such ratio was 207 percent as at December 31, 2001); and (iii) consolidated cash flow not to be less than 400 percent of consolidated interest expense (such ratio was 567 percent as at December 31, 2001).

The final component is the US\$150 million senior subordinated notes. These notes were issued in February 2001 and have a 10-year term. The notes bear interest at 10.5 percent payable semi-annually, are unsecured and have no significant financial covenant maintenance requirements.

In December 2001, the Company entered into interest rate swap contracts that converted the fixed interest rates on both the senior secured notes and the senior subordinated notes to floating terms. The interest rate for the senior secured notes, as a result of this transaction, is now set quarterly at the three-month LIBOR rate plus 2.71 percent until the maturity of the notes. The interest rate for the senior subordinated notes is now set quarterly at the three-month LIBOR rate plus 5.40 percent until February 15, 2006.

Baytex believes that cash flow generated from its operations, together with existing bank facilities, will be sufficient to finance current operations and planned capital expenditures for 2002. The timing of most of the Company's capital expenditures is discretionary and there are no material long-term capital commitments.

RISK MANAGEMENT

The exploration for and the development, production and marketing of oil and natural gas involves a wide range of business and financial risks, some of which are beyond the Company's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, interest rates and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and Baytex competes with a number of other companies, many of which have greater financial and personnel resources.

The business risks facing Baytex are mitigated in a number of ways. Geological, geophysical, engineering, environmental and economic analyses are performed on new exploration prospects and potential acquisitions to ensure acceptable rates of return. Baytex's ability to increase its production, revenue and cash flow depends on its success in acquiring, exploring for and developing new reserves and production and managing these assets in a cost efficient manner.

The Company's financial results can be significantly affected by the prices received for oil and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, Baytex has a risk management program that fixes the prices of oil and natural gas on a percentage of the total expected production volume. The objective is to lock in prices on a portion of the Company's future production to decrease exposure to market volatility and ensure the Company's ability to finance its growth. The use of derivative instruments is governed under formal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes. The Company recognizes realized gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

Baytex's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and, to some extent, natural gas prices are based on reference prices denominated in US dollars, while the majority of expenses are denominated in Canadian dollars. Baytex manages its exposure to this market risk by partially balancing US dollar denominated revenue with US dollar denominated debt.

Baytex is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term bankers' acceptance rates. In December 2001, the Company entered into interest rate swap contracts converting the fixed rate on the US denominated term notes to a floating rate reset quarterly based on the three-month LIBOR rate. There is no plan at this time to fix the rate on any of Baytex's long-term borrowings.

The Company's current position with respect to its financial instruments is detailed in Note 11 of the Consolidated Financial Statements.

NEW ACCOUNTING PRONOUNCEMENTS

The Accounting Standards Board of the Canadian Institute of Chartered Accountants ("CICA") has approved Handbook section 3062 "Goodwill and Other Intangible Assets". Section 3062, effective January 1, 2002, establishes new standards for goodwill acquired in a business combination which eliminates amortization of goodwill and instead sets forth methods to periodically evaluate goodwill for impairment. Baytex did not record goodwill on any of its past business combinations. The new standards may have an impact on future business combinations.

The Accounting Standards Board of the CICA has approved Handbook section 3870 "Stock-Based Compensation and Other Stock-Based Payments". Section 3870, effective January 1, 2002, establishes new standards for stock-based compensation including the accounting related to the Company's Stock Option Plan. The Company does not believe the adoption of this section will have a material impact on its financial statements.

Effective January 1, 2002, Baytex will adopt the requirements of the amended Handbook section 1650 "Foreign Currency Translation". The amended section eliminates the practice to defer and amortize foreign exchange gains and losses on long-term monetary items. All foreign exchange gains and losses on long-term monetary items will be recognized in earnings as they occur. At December 31, 2001, Baytex had deferred approximately \$13.7 million of foreign exchange loss.

The CICA's Emerging Issues Committee has issued Abstract 122 "Balance Sheet Classification of Callable Debt Obligations and Debt Obligations to be Refinanced". The Abstract is effective January 1, 2002 and includes guidance on the classification of borrowings made under 364-day revolving credit facilities where the entire amount would be classified as a current liability if the lender retains the right to demand repayment. At December 31, 2001, Baytex had \$73.8 million borrowed under this type of arrangement, and was included as long-term debt but under the new standard would be classified as current liability.

MANAGEMENT’S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Ltd. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP, were appointed by the Company’s shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements. Their examination included a review and evaluation of Baytex’s internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. The Committee meets with management and the independent auditors to ensure that management’s responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval.



Raymond T. Chan, CA
Senior Vice-President and Chief Financial Officer
March 1, 2002



John G. Leach, CA
Vice-President, Finance and Administration

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Baytex Energy Ltd.:

We have audited the consolidated balance sheets of Baytex Energy Ltd. as at December 31, 2001 and 2000 and the consolidated statements of operations and retained earnings (deficit) and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 1, 2002, we reported separately to the board of directors and shareholders of Baytex Energy Ltd. on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 14, United States Accounting Principles and Reporting and Note 15, Condensed Consolidating Financial Information.



Calgary, Alberta
March 1, 2002

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31 (thousands)	2001	2000
ASSETS		
Current assets		
Accounts receivable	\$ 44,300	\$ 38,400
Properties held for sale (note 13)	46,895	—
	91,195	38,400
Deferred financing charges	8,674	583
Unrealized foreign exchange loss	13,698	—
Petroleum and natural gas properties (note 3)	867,177	791,014
	\$ 980,744	\$ 829,997
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	\$ 64,334	\$ 80,774
Current portion of long-term debt	2,000	—
	66,334	80,774
Long-term debt (note 4)	403,922	213,883
Deferred revenue (note 5)	18,694	—
Unrealized foreign exchange gain/	—	1,655
Provision for future site restoration costs	20,541	15,918
Future income taxes (note 8)	152,473	138,445
	661,964	450,675
SHAREHOLDERS' EQUITY		
Share capital (note 6)	394,734	326,767
Retained earnings (deficit)	(75,954)	52,555
	318,780	379,322
	\$ 980,744	\$ 829,997

See accompanying notes to the consolidated financial statements.

On behalf of the Board



John A. Brussa
Director



W. A. Blake Cassidy
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

Years Ended December 31 (thousands, except per share data)	2001	2000
Revenue		
Petroleum and natural gas sales	\$ 329,700	\$ 286,226
Royalties	(57,805)	(50,426)
	271,895	235,800
Expenses		
Operating	83,439	53,815
General and administrative	5,262	4,331
Interest on long-term debt	33,850	13,825
Depletion, depreciation and amortization (note 3)	367,384	84,602
Site restoration costs	3,912	3,430
	493,847	160,003
Income (loss) before income taxes	(221,952)	75,797
Income taxes (recovery) (note 8)		
Current	7,128	8,503
Future	(100,571)	23,506
	(93,443)	32,009
Net income (loss)	(128,509)	43,788
Retained earnings, beginning of year	52,555	19,838
Accounting policy change (note 8)	—	(11,071)
Retained earnings (deficit), end of year	\$ (75,954)	\$ 52,555
Net income (loss) per common share (note 7)		
Basic	\$ (2.60)	\$ 1.04
Diluted	\$ (2.60)	\$ 1.01

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 (thousands, except per share data)	2001	2000
Cash provided by (used in):		
Operating activities		
Net income (loss)	\$ (128,509)	\$ 43,788
Items not affecting cash:		
Amortization of deferred charges	1,854	—
Site restoration costs	3,912	3,430
Depletion, depreciation and amortization (note 3)	367,384	84,602
Future income taxes (recovery)	(100,571)	23,506
Cash flow from operations	144,070	155,326
Change in non-cash working capital (note 9)	5,682	512
Deferred revenue (note 5)	18,694	—
	168,446	155,838
Financing activities		
Issue of senior subordinated term notes	227,895	—
Increase (decrease) in bank loan	(90,474)	43,825
Increase in deferred financing charges	(9,037)	—
Repurchase of common shares (note 6)	(860)	—
Issue of common shares	1,444	3,383
	128,968	47,208
Investing activities		
Corporate acquisitions (note 2)	(249,152)	(221,754)
Items not affecting cash		
Shares issued on acquisition	68,104	112,958
Assumption of long-term debt	36,356	50,433
Assumption of working capital (surplus) deficiency	(2,734)	13,604
	(147,426)	(44,759)
Petroleum and natural gas property expenditures	(189,515)	(172,656)
Disposal of petroleum and natural gas properties	62,582	9,553
Increase (decrease) in materials and supplies	232	(3,195)
Properties held for sale (note 13)	46,895	—
Change in non-cash working capital (note 9)	(70,182)	8,011
	(297,414)	(203,046)
Change in cash during the year	—	—
Cash, beginning of year	—	—
Cash, end of year	\$ —	\$ —
Cash flow from operations per common share (note 7)		
Basic	\$ 2.91	\$ 3.68
Diluted	\$ 2.87	\$ 3.58

See accompanying notes to the consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years Ended December 31, 2001 and 2000 (all amounts in thousands, except per unit and volume amounts)

1. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles within the framework of the accounting policies summarized below:

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

Measurement uncertainty

Amounts recorded for depreciation, depletion and amortization and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. The Company's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Petroleum and natural gas operations

The Company follows the full cost method of accounting whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future costs based on current costs which are to be incurred in developing proved reserves, are depleted and depreciated on a unit of production basis using estimated gross proved petroleum and natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on sales of properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the “ceiling test”). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves and period-end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for future site restoration costs

Estimates are made of the future site restoration costs relating to the Company’s petroleum and natural gas properties at the end of their economic life, based on year-end values, in accordance with current legislative requirements and industry practice. Annual charges are provided for on a unit of production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

Joint interests

A portion of the Company’s exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Company’s proportionate interest in such activities.

Foreign currency translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Unrealized gains or losses on long-term debt are deferred and amortized over the remaining term of the debt instrument on a straight-line basis.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Financing charges

Financing costs related to the issuance of the senior secured term notes and the senior subordinated term notes have been deferred and are amortized over the term of the respective notes on a straight-line basis.

Financial instruments

The Company utilizes derivative financial instruments to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. All transactions of this nature entered into by the Company are related to an underlying financial position or to future petroleum and natural gas production. The Company does not use derivative financial instruments for trading purposes. Costs and gains on derivative contracts are recognized in income in the same period that the transactions are settled. The fair values of derivative instruments are not recorded in the consolidated balance sheets.

Gains and losses related to financial instruments that have been closed prior to the settlement dates are deferred and recognized in the consolidated statements of operations over the original settlement period.

Future income taxes

Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Flow-through shares

The Company has financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company records the gross carrying value of the expenditures and records a future tax liability for the tax benefits renounced to subscribers.

Stock compensation

The Company's stock-based compensation plans are described in note 6 (c). No compensation expense is recognized when stock options are issued. The consideration paid on the exercise of stock options is credited to share capital. Benefits under the stock appreciation rights plan are charged to net income.

Earnings per share

Effective January 1, 2001, the Company adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to the calculation and disclosure of per share amounts. Basic earnings per share and basic cash flow from operations per share are computed by dividing earnings and cash flow from operations by the weighted average number of common shares outstanding during the year. Diluted per share amounts reflect the potential dilution that could occur if options or warrants to purchase common shares were exercised. The treasury stock method is used to determine the dilutive effect of stock options and warrants, whereby any proceeds from the exercise of stock options or other dilutive instruments are assumed to be used to purchase common shares at the average market price during the period.

2. CORPORATE ACQUISITIONS

Effective May 1, 2001, the Company acquired all of the issued and outstanding shares of OGY Petroleums Ltd. ("OGY"), a public company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration	
Cash	\$ 50,683
Transaction costs	3,100
	53,783
Issue of 1,169,481 common shares	14,057
	<u>\$ 67,840</u>
Net Assets Acquired	
Petroleum and natural gas properties	\$ 116,607
Future income taxes	(36,127)
Future site restoration costs	(1,844)
	78,636
Working capital deficiency	(4,809)
Long-term debt	(5,987)
	<u>\$ 67,840</u>

Effective June 1, 2001, the Company acquired all of the issued and outstanding shares of Triumph Energy Corporation ("Triumph"), a public company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration	
Cash	\$ 82,337
Transaction costs	11,306
	93,643
Issue of 4,949,245 common shares	54,047
	<u>\$ 147,690</u>
Net Assets Acquired	
Petroleum and natural gas properties	\$ 248,480
Future income taxes	(77,751)
Future site restoration costs	(213)
	170,516
Working capital	7,543
Long-term debt	(30,369)
	<u>\$ 147,690</u>

Effective May 1, 2000, the Company acquired all of the issued and outstanding shares of Bellator Exploration Inc. ("Bellator"), a public company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration	
Cash	\$ 39,933
Transaction costs	3,386
	<hr/> 43,319
Issue of 8,785,287 common shares	101,734
	<hr/> \$ 145,053
Net Assets Acquired	
Petroleum and natural gas properties	\$ 281,586
Future income taxes	(76,627)
Future site restoration costs	(494)
	<hr/> 204,465
Working capital deficiency	(13,339)
Long-term debt	(46,073)
	<hr/> \$ 145,053

Effective August 1, 2000, the Company acquired all of the issued and outstanding shares of Aquilo Energy Inc. ("Aquilo"), a private company involved in the exploration, development and production of oil and natural gas in Western Canada. The acquisition has been accounted for by the purchase method of accounting as follows:

Consideration	
Cash	\$ 1,440
Issue of 956,013 common shares	11,224
	<hr/> \$ 12,664
Net Assets Acquired	
Petroleum and natural gas properties	\$ 20,682
Future income taxes	(3,310)
Future site restoration costs	(83)
	<hr/> 17,289
Working capital deficiency	(265)
Long-term debt	(4,360)
	<hr/> \$ 12,664

3. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31	2001	2000
Petroleum and natural gas properties	\$ 1,810,193	\$ 1,242,093
Accumulated depletion and depreciation	(950,096)	(458,391)
Materials and supplies	7,080	7,312
	\$ 867,177	\$ 791,014

During 2001, \$5.3 million (2000 – \$4.3 million) of corporate expenses relating to exploration and development activities were capitalized. In calculating the depletion provision for 2001, \$85.3 million (2000 – \$73.3 million) of costs relating to undeveloped properties and materials and supplies of \$7.1 million (2000- \$7.3 million) were excluded from costs subject to depletion.

As a result of the ceiling test performed at December 31, 2001, the Company recorded additional depletion and depreciation on its petroleum and natural gas properties of \$234.5 million (\$131.3 million net of income tax).

At December 31, 2001, the estimated future site restoration costs to be accrued over the life of the remaining proved reserves are \$30.0 million (2000 – \$19.0 million).

4. LONG-TERM DEBT

As at December 31	2001	2000
Bank loan	\$ 73,820	\$ 125,671
Senior secured term notes (US\$57 million)	90,778	85,511
Senior subordinated term notes (US\$150 million)	238,890	–
Other long-term debt	2,434	2,701
	405,922	213,883
Less: current portion	2,000	–
	\$ 403,922	\$ 213,883

Bank loan

The bank loan consists of an operating loan and a revolving loan, which are provided by a syndicate of chartered banks. The bank facilities can be drawn in either Canadian or US funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities are subject to periodic review and are secured by a charge over all of the Company's assets. The security is shared pari passu with the senior secured term notes. At December 31, 2001, the facilities are limited to total commitment under the facilities of \$110 million and a \$200 million borrowing base of total senior funded debt, which is defined to include the senior secured term notes.

Senior secured term notes

On November 13, 1998, the Company issued US\$57 million of senior secured term notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. These notes are governed by financial and other corporate covenants and are secured by a charge over all of the Company's assets, which security is shared pari passu with the bank facilities. In December 2001, the Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 2.71 percent until the maturity of these notes.

Senior subordinated term notes

On February 12, 2001, the Company issued US\$150 million of senior subordinated term notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank facilities and senior secured term notes. In December 2001, the Company entered into interest rate swap contracts converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.40 percent until February 15, 2006.

Other long-term debt

At December 31, 2001, other long-term debt included a \$2 million debenture term loan provided to a subsidiary of the Company. The loan bears interest at a Canadian chartered bank's prime lending rate plus 2.5% per annum with a minimum rate of 10% per annum. This amount is repayable on March 15, 2002 and has been reclassified as a current liability as at December 31, 2001.

5. DEFERRED REVENUE

During 2001, the Company renegotiated certain derivative contracts related to 2002 and received a net payment of \$18.7 million. This amount has been recorded as deferred revenue and will be recognized during 2002 based on the notional volumes of the original contracts.

6. SHARE CAPITAL

(a) Authorized

The Company has an unlimited number of common shares in its authorized share capital.

(b) Issued

	2001		2000	
	# Shares	Amount	# Shares	Amount
Balance, beginning of year	45,797	\$ 326,767	35,469	\$ 210,426
Shares issued for corporate acquisitions (note 2)	6,119	68,104	9,741	112,958
Stock options exercised (note 6 (c))	314	1,444	465	1,842
Normal course issuer bid (note 6 (e))	(222)	(860)	—	—
Flow-through shares issued (note 6 (d))	—	—	122	1,604
Future tax related to flow-through shares	—	(721)	—	—
Share issue costs, net of future tax	—	—	—	(63)
Balance, end of year	52,008	\$ 394,734	45,797	\$ 326,767

(c) Stock options and stock appreciation rights

The Company grants stock options to its employees and directors at the market price of the common shares at the time of the grant. The options vest over three years and have a term of four years. At December 31, 2001, 4.6 million common shares of the Company are reserved under the stock option plan for issuance.

	Options	Price Range	Weighted Average Exercise Price
Outstanding December 31, 1999	3,146	\$ 2.15 to \$ 18.75	\$ 6.73
Granted	2,273	\$ 8.40 to \$ 15.50	\$ 10.98
Exercised	(465)	\$ 2.15 to \$ 8.10	\$ 3.95
Cancelled	(912)	\$ 3.80 to \$ 18.75	\$ 11.92
Outstanding December 31, 2000	4,042	\$ 3.30 to \$ 15.50	\$ 8.26
Granted	2,478	\$ 3.51 to \$ 13.30	\$ 6.17
Exercised	(314)	\$ 3.30 to \$ 12.25	\$ 4.84
Cancelled	(1,738)	\$ 3.80 to \$ 15.50	\$ 11.25
Outstanding December 31, 2001	4,468	\$ 3.30 to \$ 10.75	\$ 6.19

The following table summarizes information about the stock options outstanding at December 31, 2001:

	Number Outstanding at December 31, 2001	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2001	Weighted Average Exercise Price
\$ 3.30 to \$ 5.00	2,866	2.8	\$ 4.43	606	\$ 4.04
\$ 5.01 to \$ 7.00	247	2.0	\$ 5.96	131	\$ 5.39
\$ 7.01 to \$ 9.00	285	1.4	\$ 8.51	195	\$ 8.44
\$ 9.01 to \$ 10.75	1,070	2.8	\$10.32	357	\$ 10.32
Total	4,468	2.6	\$ 6.19	1,289	\$ 6.58

The Company has granted stock appreciation rights ("Rights") to certain employees. Holders of the Rights are entitled to receive incentive payments based on the difference between market price of the Company's common shares and exercise price of the Rights. The exercise price of the Rights is determined based on the market price of the Company's common shares at the time the Rights were granted. The Rights vest over three years and have a term of four years.

A total of 202,334 Rights are outstanding and vested at December 31, 2001, (December 31, 2000 – 209,000) with exercise prices ranging from \$4.50 to \$7.67 and a weighted average exercise price of \$7.15 (December 31, 2000 – \$7.06). During 2001, 6,666 (2000 – 191,000) Rights were exercised at a weighted average price of \$4.50 (2000 – \$6.67).

(d) Flow-through shares

In accordance with the terms of flow-through share offerings entered into by the Company and one of its subsidiaries, and pursuant to certain provisions of the Income Tax Act (Canada), the Company and its subsidiary fulfilled their commitment to renounce for income tax purposes, exploration expenditures of \$1.6 million in 2001 (2000 – \$4.0 million) to the subscribers of the flow-through shares.

(e) Normal course issuer bid

During the year ended December 31, 2001, the Company acquired 222,400 (2000 – nil) of its common shares through a normal course issuer bid program at an average cost of \$3.87 per share. The shares purchased under the normal course issuer bid were cancelled. In December 2001, the Company renewed its normal course issuer bid to purchase up to 5.2 million common shares of the Company during the 12-month period beginning December 27, 2001 and ending December 26, 2002.

7. NET INCOME (LOSS) AND CASH FLOW PER SHARE

The Company has adopted retroactively the treasury stock method to assess the potential impact of outstanding stock options and stock appreciation rights on earnings and cash flow from operations per share. The new standard has been applied retroactively and prior periods have been restated resulting in diluted net income and cash flow from operations per share for the year ended December 31, 2000 being adjusted to \$1.01 from \$1.00 and to \$3.58 from \$3.50, respectively. Had the new standard not been adopted, diluted net loss and cash flow from operations per share for the year ended December 31, 2001 would have been \$2.60 and \$2.71, respectively.

The number of shares used in the calculation of diluted net income and cash flow from operations per share for the year ended December 31, 2001 of 50.2 million included the weighted average number of shares outstanding of 49.5 million plus 0.7 million shares related to the dilutive effect of stock options. For the year ended December 31, 2000, the number of shares used in the calculation of net income and cash flow per share were 43.4 million and included the weighted average number of shares outstanding of 42.2 million plus 1.2 million shares related to the dilutive effect of stock options.

The diluted net income and cash flow from operations per share discussed above did not include 3.4 million (2000 – 1.4 million) of stock options, on a weighted average basis, because the respective exercise prices exceeded the average market prices of the common shares.

8. INCOME TAXES

On January 1, 2000 the Company adopted the liability method of accounting for income taxes. The application of the liability method for income taxes resulted in an increase of \$15.6 million in capital assets, a decrease of \$11.1 million in retained earnings and an increase of \$26.7 million in future tax liability as of January 1, 2000.

The provision for income taxes has been computed as follows:

Years ended December 31	2001	2000
Income (loss) before income taxes	\$ (221,952)	\$ 75,797
Expected income taxes (recovery) at the statutory rate of 44.0% (2000 – 45.0%)	\$ (97,659)	\$ 34,109
Increase (decrease) in taxes resulting from:		
Crown royalties	19,870	17,034
Resource allowance	(22,560)	(25,148)
Alberta Royalty Tax Credit	(224)	(192)
Rate change	183	(400)
Unrecorded assets	–	(927)
Other	(181)	(970)
Large Corporation Tax and provincial capital tax	7,128	8,503
Provision for income taxes	\$ (93,443)	\$ 32,009

The components of future income taxes are as follows:

As at December 31	2001	2000
Future income tax liabilities:		
Capital assets	\$ 180,764	\$ 172,579
Future income tax assets:		
Abandonment costs	(9,038)	(7,099)
Loss carry-forward	(7,528)	(21,170)
Other	(11,725)	(5,865)
Future income taxes	\$ 152,473	\$ 138,445

9. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

As at December 31	2001	2000
Current assets	\$ (23,440)	\$ 1,810
Current liabilities	(41,060)	6,713
	\$ (64,500)	\$ 8,523
Changes in non-cash working capital related to:		
Operating activities	\$ 5,682	\$ 512
Investing activities	(70,182)	8,011
	\$ (64,500)	\$ 8,523

During the year the Company made the following cash outlays in respect of interest expense and current income taxes.

Years ended December 31	2001	2000
Interest on long-term debt	\$ 22,889	\$ 14,083
Current income taxes	\$ 9,057	\$ 6,214

10. FINANCIAL INSTRUMENTS

The Company's financial instruments recognized in the consolidated balance sheets consist of accounts receivable, current liabilities and long-term borrowings. The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The fair values of financial instruments other than long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2001 the Company had \$73.8 million of variable rate loans. There were no instruments in place at December 31, 2001 to fix the interest rate on this variable rate debt. At December 31, 2001 and 2000 the reported values of the Company's senior secured term notes, bank loan and other long-term debt approximate their fair values. At December 31, 2001, the fair value of the Company's senior subordinated term notes was \$224.5 million compared to a reported value of \$238.9 million.

11. DERIVATIVE CONTRACTS

The nature of the Company's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. In 2001, petroleum and natural gas sales were reduced by \$9.3 million (2000 – \$53.2 million) due to derivative contracts.

At December 31, 2001, the Company had derivative contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2002	10,000 bbls/d	US\$ 20.00 – \$ 25.00	WTI
Fixed price	Calendar 2002	1,000 bbls/d	US\$ 21.10	WTI
	Calendar 2002	1,500 bbls/d	US\$ 21.09	WTI
Natural Gas				
Fixed price	January 2002 – October 2002	10,000 GJ/d	CAN\$ 4.25	AECO
	January 2002 – October 2002	10,000 GJ/d	CAN\$ 3.37	AECO
Price collar	January 2002 – October 2002	10,000 GJ/d	CAN\$ 3.75 – \$ 5.00	AECO
	January 2002 – October 2002	10,000 GJ/d	CAN\$ 3.00 – \$ 3.90	AECO

Period	Principal	Rate	Unrecognized gain at December 31, 2001
Interest rate swap			
December 2001 to November 2004	US\$57 million	3-month LIBOR plus 2.71%	\$ 732
December 2001 to February 2006	US\$150 million	3-month LIBOR plus 5.40%	\$ 790

Period	Principal	Rate	Unrecognized loss at December 31, 2001
Foreign currency swap			
January 1998 to December 2005	US\$315,000 per month	CAN/US\$1.4228	\$2,225

12. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

13. SUBSEQUENT EVENTS

Subsequent to December 31, 2001 the Company completed certain property sales and received net proceeds of \$46.9 million, which were used to repay borrowings under its bank facilities. As a result of the completion of these property sales, the Company's loan facilities were reviewed and the total commitment and the borrowing base were revised to \$85 million and \$175 million, respectively (see Note 4).

14. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Company's Form 40-F, which is filed with the United States Securities and Exchange Commission.

QUARTERLY INFORMATION

	2001				2000			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL (unaudited)								
(\$ thousands except per share amounts)								
Petroleum and natural gas sales	64,327	101,689	84,454	79,230	74,909	93,051	67,810	50,456
Cash flow from operations	24,353	46,330	35,770	37,617	34,501	52,006	38,761	30,058
Per share – basic	0.47	0.89	0.74	0.82	0.73	1.17	0.94	0.84
Net income (loss)	(140,073)	2,351	3,683	5,530	4,309	17,258	12,203	10,018
Per share – basic	(2.68)	0.04	0.08	0.12	0.08	0.39	0.29	0.28
Capital expenditures, net	(32,008)	33,913	329,674	44,506	42,690	58,761	250,069	32,691

OPERATIONS

Production								
Conventional oil and NGLs (bbls/d)	5,808	6,077	4,782	3,911	4,245	3,970	4,087	4,125
Heavy oil (bbls/d)	24,528	29,078	26,545	25,970	26,904	25,260	17,396	10,326
Total oil and NGLs (bbls/d)	30,336	35,155	31,327	29,881	31,149	29,230	21,483	14,451
Natural gas (mmcf/d)	75.9	78.2	71.3	57.6	54.7	58.4	59.2	58.4
Barrels of oil equivalent (boe/d @ 6:1)	42,990	48,187	43,201	39,483	40,268	38,966	31,332	24,188

AVERAGE PRICES

WTI oil (US\$/bbl)	20.43	26.49	27.96	28.73	31.86	31.58	28.63	28.73
Edmonton par oil (\$/bbl)	31.00	40.37	42.19	43.00	48.34	46.36	41.45	41.34
BTE – Light oil (\$/bbl)	25.41	35.37	37.53	38.65	43.07	42.35	37.92	37.50
Heavy oil (\$/bbl)	10.39	23.75	16.77	14.62	17.33	32.60	30.36	29.40
Total oil (\$/bbl)	13.27	25.76	19.94	17.77	20.83	33.93	31.79	31.71
BTE natural gas (\$/mcf)	3.09	3.35	5.11	6.83	5.77	3.96	3.57	2.85
BTE oil equivalent (\$/boe @ 6:1)	14.82	24.23	22.88	23.41	23.96	31.38	28.51	25.83

SHARE TRADING INFORMATION

BTE –Toronto Stock Exchange								
High (\$)	5.25	11.50	13.55	14.84	15.80	16.70	15.50	12.55
Low (\$)	3.00	4.64	9.60	9.00	9.00	11.75	11.55	8.25
Close (\$)	4.37	4.80	9.80	12.15	10.00	14.55	14.00	11.70
Average daily volume	455,000	156,000	203,000	191,000	89,000	107,000	111,000	83,000

FIVE YEAR SUMMARY

	2001	2000	1999	1998	1997
FINANCIAL					
(\$ thousands except per share amounts)					
Petroleum and natural gas sales	329,700	286,226	120,087	102,337	123,839
Cash flow from operations	144,070	155,326	62,703	43,920	63,879
Per share – basic	2.91	3.68	1.77	1.29	2.10
Net income (loss)	(128,509)	43,788	14,128	(38,382)	10,989
Per share – basic	(2.60)	1.04	0.40	(1.12)	0.36
Capital expenditures, net	376,085	384,857	74,313	39,314	166,654
Working capital (deficiency)	24,861	(42,374)	(16,130)	42,432	(32,342)
Long-term debt	403,922	213,883	116,382	157,093	98,555
Total assets	980,744	829,227	419,163	413,809	443,831
OPERATIONS					
Production					
Conventional oil and NGLs (bbls/d)	5,152	4,107	4,457	5,475	6,053
Heavy oil (bbls/d)	26,533	20,005	5,574	3,517	2,842
Total oil and NGLs (bbls/d)	31,685	24,112	10,031	8,992	8,895
Natural gas (mmcf/d)	70.8	57.7	56.1	75.9	78.7
Barrels of oil equivalent (boe/d @ 6:1)	43,488	33,721	19,681	21,642	22,012
Reserves					
Crude oil and NGLs (mbbls)					
Proved	110,221	105,022	56,420	54,395	55,765
Probable	52,334	48,038	37,055	28,807	28,374
Total	162,555	153,060	93,475	83,202	84,139
Natural gas (mmcf)					
Proved	134,653	98,048	103,947	105,724	201,630
Probable	42,767	30,202	47,604	44,289	71,337
Total	177,420	128,250	151,551	150,013	272,967
Wells drilled (gross)					
Oil	63	267	109	91	79
Gas	81	28	28	47	49
Other	3	4	1	–	–
Dry	32	23	25	33	58
Total	179	322	163	171	186

CORPORATE INFORMATION

BOARD OF DIRECTORS

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W.A. Blake Cassidy
Retired Banker

Raymond T. Chan
Senior Vice-President
Baytex Energy Ltd.

Fred C. Coles
Independent Businessman

Dennis L. Nerland
Partner
Shea Nerland Calnan

Dale O. Shwed
President
Baytex Energy Ltd.

OFFICERS

Dale O. Shwed
President and Chief Executive Officer

Raymond T. Chan, CA
Senior Vice-President and
Chief Financial Officer

Ralph W. Gibson
Vice-President, Marketing

Daniel B. Horner, LLB
Vice-President, Land

John G. Leach, CA
Vice-President, Finance
and Administration

S. Dale McAuley
Vice-President, Operations

Richard W. Naden
Vice-President, Production

Garry J. Wasylycia
Vice-President, Exploration

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

HEAD OFFICE

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845
Website: www.baytex.ab.ca

AUDITORS

Deloitte & Touche LLP

BANKERS

Royal Bank of Canada
Bank of Montreal
BNP Paribas (Canada)

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Outtrim Szabo Associates Ltd.

TRANSFER AGENT

Valiant Corporate Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol BTE

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent (6 mcf: 1 bbl)
mmboe	million barrels of oil equivalent (6 mcf: 1 bbl)
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids

ADVISORY

Certain statements in this Report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this Report contains forward-looking statements relating to Management's approach to operations, expectations relating to amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels, estimated amount and value of oil and gas reserves and estimated value of undeveloped land. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency and exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; and other factors, many of which are beyond the control of the Company. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

DIRECTORS



JOHN A. BRUSSA

Mr. Brussa has been a Baytex director since October 1997. He has been a partner at the law firm Burnet, Duckworth & Palmer LLP since 1987 and specializes in the practice of taxation law. Mr. Brussa serves on the board of directors of a number of oil and gas companies, mutual fund trusts, investment dealers and non-profit organizations.



W. A. BLAKE CASSIDY

Mr. Cassidy has been a Baytex director since February 1994. He is a retired banker after a 38-year career at the Canadian Imperial Bank of Commerce. He has extensive experience in both energy banking and private banking.



RAYMOND T. CHAN

Mr. Chan joined Baytex as Senior Vice-President, Chief Financial Officer and a Director in October 1998. He began his career in the Canadian oil and gas industry in 1981 and served as Chief Financial Officer of several companies, including Tarragon Oil and Gas Limited. Mr. Chan graduated from the University of Saskatchewan with a Bachelor of Commerce degree in 1977 and obtained his Chartered Accountant designation in 1979.



FRED C. COLES

Mr. Coles has been a Baytex director since May 1998. He served as Chairman and President of Coles Gilbert Associates Ltd., a petroleum engineering consulting firm, from 1982 through 1994. Coles Gilbert has been renamed Gilbert Laustsen Jung Associates Ltd. Mr. Coles is a professional engineer with over 30 years of experience in the oil and gas industry. He serves on the board of directors of several public companies.



DENNIS L. NERLAND

Mr. Nerland has been a Baytex director from February 1994 to October 1997 and again since May 1998. He is a partner at Shea Nerland Calnan, a law firm specializing in consulting and strategic planning in the industrial, oil and gas, high and bio-technical and entertainment industries.



DALE O. SHWED

Mr. Shwed founded Baytex in June 1993 and has since served as President, Chief Executive Officer and a Director. He has 20 years of experience in the Canadian oil and gas industry, including positions with Amoco Canada Petroleum Corporation Ltd., Westmin Resources Ltd. and Inverness Petroleum Ltd. Mr. Shwed graduated from the University of Alberta with a Bachelor of Science degree in geology in 1980.



Suite 2200, Bow Valley Square II, 205 - 5th Avenue S.W. Calgary, Alberta T2P 2V7

www.baytex.ab.ca